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The H-Coal and SRC-II Processes

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Technical Report

The H-Coal and SRC-II Processes

by

Daniel Heiser

February 1982

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16. ABSTRACT

This report examines the product quality and cost of the H-Coal and Solvent Refined Coal II (SRC-II) processes. Available design studies addressing these processes are critiqued and the most accurate description and cost estimates are selected.

The critique of the available studies shows that costs in constant dollars have risen dramatically over the last five years and that most of the available studies are now out of date. A recent study by the Department of Energy contains the most recent analysis of the SRC-II process and a recent 1981 report by Ashland contains the most accurate information on the H-Coal processes.

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Table of Contents

		Page
I.	Introduction	1
II.	Financial Input Factors	1
III.	Process Description and Economic Analysis of the H-Coal and SRC-II Processes	6
	A. The H-Coal Process	7
	B. The SRC-II Process	25
IV.	Summary	47

I. Introduction

As the nation investigates several alternatives for producing synthetic fuels from our coal reserves, the major question arising is what is the most efficient way to utilize our coal resources. The answer involves determining what kind of synthetic fuels to produce and what method should be used to produce these fuels. Much attention is being directed towards development of synthetic petroleum products. This report will attempt to identify the products and costs associated with two processes which produce synthetic crude oil from coal, the H-Coal process and the SRC-II process.

The first step in this attempt will be the identification of a set of financial and technical parameters upon which to base the comparison of costs from various studies originally using different bases. Such parameters include plant size, capital charge rates, etc. This identification will be presented in Section II. The second step will start with a survey of the economic studies of the H-Coal and SRC-II processes. These studies will be compared techanically and economically to determine which represents the best product and cost estimates for each process. Once the best study (or studies) has been selected in each case, its financial parameters will be adjusted to those determined in the previous section. The final product cost of each process will then be estimated in terms of dollars per million BTU (mBTU).

A summary of the cost estimates will be included at the end of this report.

II. Financial Input Factors

Differences in costs developed from recent studies on coal liquefaction can often result because of two major factors. One, the costs may differ because of differences in the financial parameters specified (such as interest rates, debt/equity ratio, capital charge rate, etc.). Two, the costs may differ because hardware costs for each phase of the process itself were estimated using different cost estimation techniques or were based on different process requirements. The objective of this section is to develop a common set of financial and economic parameters for all studies to eliminate the first cause of these differences. Hardware or process costs involve intimate knowledge of the specific coal liquefaction processes and the detailed evaluation of each study's procedures in these areas is beyond the scope of this report. However, some evaluation of each study's technical/economic accuracy will be made based on the overall level of detail of the engineering design and the source and data of the process parameters.

To determine a reasonable range of the financial parameters applicable to such studies, a survey of recent studies on coal

liquefaction processes was taken.[1,2,3,4,5,6] Two financial scenarios representing two somewhat extreme cases were found and are shown in Table 1.

The first scenario represents a situation where utility-type financing or loan guarantees are available and was taken from a report by ESCOE.[3] Debt financing is assumed to be 40 percent of total financing. The overall capital charge rate for this scenario is 11.5 percent. The second scenario was taken from a Chevron study[1] and assumes total reliance on equity financing. The overall capital charge rate of this scenario is 30 percent.

To mention one aspect of the parameters of Table 1, capital costs are often estimated in terms of "instantaneous" investment (i.e., as if the costs would occur all at once). In reality, this does not take place as plants are designed and constructed over a period of time. Each of the two financial scenarios has a different capital investment schedule to account for this. These investment schedules, along with the cost of interest during construction are used to adjust the instantaneous capital cost estimates to full-life capital cost investment. The interest rate during construction used here will be 6 percent per year and was taken from a report by ICF.[2] Since all operations are performed in constant $1981, this 6 percent per annum opportunity cost does not include the effects of inflation.

For the purposes of this report, the products of each process will be measured in terms of fuel oil equivalent barrels (FOEB), each FOEB containing 5.9 million Btu. This is a common unit for measuring the equivalent energy output of a fuel. To eliminate cost differences due to economies of scale, all plants will be normalized to an output of 50,000 FOEB per calender day (FOEB/D). Because capital costs are usually not in direct proportion to their plant sizes, a scaling factor is needed. This scaling factor is an exponent which is applied to the ratio of plant sizes to determine the effect on capital costs. The capital scaling factor used in this study will be 0.75, which is an average of factors found from various studies.[2,5,7,8]

Operating costs need to be adjusted differently than capital costs. To adjust labor and supervision costs to the common 50,000 BFOE/D plant size, a scaling factor of 0.2 will be used.[3,7] Maintenance costs, taxes and insurance, and general services, etc., will be assumed to be the same percentage of plant investment as specified by individual studies. The use of coal, catalysts, chemicals, utilities, fuel, and natural gas will also be assumed to vary in proportion to plant size. Electricity costs will be normalized to 3.5 cents per kilowatt hour. Also included in the total annual operating cost will be a 6 percent real interest charge on working capital.[2]

Table 1

Common Financial Parameters*

Financial Parameters	Low Cost Case[1]	High Cost Case[2]
Discounted Cash Flow Rate of Return on Investment, Percent	Not Available	15
Project Life, Yrs.	20	20
Construction Period, Yrs.	4	4
Investment Schedule, %/Yr.	9/25/36/30	10/15/25/50
Plant Start Up Ratios	50, 90, 100...	50/100
Nominal Debt Interest Rate, Percent	10	-
Investment Tax Credit, %	9	10
Tax Life, Yrs.	15	13
Debt/Equity Ratio	40/60	0/100
Resulting Capital Charge Rate, Percent	11.5	30

* All calculations assume constant first quarter 1981 dollars. The interest rates shown do not include the effects of inflation.

A common contingency factor will also be used to increase the comparability of the various studies. Historical evidence has shown that a variety of technical problems emerge whenever a plant is constructed from conceptual stage to the commercial stage. This usually results in an increase in cost due to the need for more expensive material of construction, more complex equipment specifications and sometimes the need for additional processing equipment. The contingency factor to be used in this analysis will be 15 percent, based on a survey of several studies.[2,3,9, 10,11,12]

Costs for feedstock and by-product credits will also be normalized. The cost of bituminous coal (in 1981 dollars) will be assumed to be $27.50 per ton. The cost of subbituminous coal and lignite will be assumed to be $17 per ton and $10 per ton, respectively. By-product credits for sulfur, ammonia, and phenol will be normalized to $50 per ton, $180 per ton, and $113 per barrel, respectively.

The inflation rate for adjusting the cost of studies to 1981 dollars will be based on the chemical engineering plant cost index. For 1976, 1977, 1978, 1979, and 1980, the resulting inflation rates were 5 percent, 6 percent, 7 percent, 9 percent, and 9 percent, respectively. The only real cost increases projected in this study were for fuel oil and natural gas used to operate the plant. This is estimated to be 2 percent per year. These common technical/economic factors are summarized in Table 2.

While all these adjustments will increase the comparability of overall product costs, they do not address the differences in the products produced by the various synfuel processes. It is generally appropriate to attempt to allocate the costs of processing in accordance to the expected market values of the various products. To do otherwise would be to mislead oneself that the premium products of a process were relatively inexpensive (while the low quality products would also be misleadingly expensive). Thus, some relationship between the values of the various fuels is needed in order to determine representative and comparable costs for each fuel.

A product value approach will be utilized to estimate costs for individual products. This technique assumes that future energy prices for particular products will maintain a fixed ratio to each other. All prices are normalized relative to a reference product, which here is chosen to be gasoline. A relationship between various fuels similar to that reported in the ICF report will be used and is as follows:

1. If the cost of unleaded regular gasoline is $G/mBtu,

2. The cost of No. 2 fuel oil is (0.82)(G)/mBtu, and

Table 2

Process Cost Inputs and Other Factors Common to All Studies

Cost Inputs and Other Factors	Value
Product Yield	50,000 BPCD
Coal - Bituminous	$27.50/wet ton
- Subbituminous	$17.00/wet ton
- Lignite	$10.00/wet ton
Operating Cost	
a) Utilities	$0.035/kw-HR
b) Interest on Working Capital	6% of working capital per year.
c) Fuel Cost	$35/bbl
Scaling Factors	
a) Capital Costs	0.75
b) Labor Costs	0.20
c) Maintenance, Taxes Insurance, General Services, etc.	Same percentage of plant investment as specified by each individual study.
d) Coal, Catalysts and Chemicals, Utilities, Fuel, Natural Gas	Amount varies directly proportional to plant size.
By-Product Credit	
a) Sulfur	$50/ton
b) Ammonia	$180/ton
c) Phenol	$113/bbl
Contingency Factor	15%
Inflation Rate	
a) 1976	5%
b) 1977	6%
c) 1978	7%
d) 1979	9%
e) 1980	9%
Real Cost Increases (%/year)	
a) Fuel Oil	2%
b) Natural Gas	2%

3. The cost of LPG is (0.77)(G)/mBtu.[2]

Since unleaded premium gasoline is produced in some cases a relationship between this fuel and regular gasoline is also needed. Since a history of the relationship between these two fuels was not readily available, a history of the cost ratio of leaded premium to leaded regular gasoline was used. This relationship indicated a cost ratio of 1.075.[13] This product cost relationship was then applied to premium and regular unleaded gasoline.

A price relationship between SNG and the reference was also needed. This may be determined by assuming that SNG will have the same relationship to gasoline as natural gas. However, the wellhead price of natural gas is just in the process of being deregulated; therefore, it is incorrect to use the current gasoline/natural gas price relationship. Instead, a method used by Mobil, and a method which relates the natural gas price to that of No. 2 fuel oil will be utilized. These two methods are described below.

In a study examining the production of gasoline from coal one of the scenarios examined by Mobil was the co-production of SNG and gasoline.[14] To obtain a realistic value for the SNG produced, Mobil estimated the cost of SNG from a coal-gasification plant producing essentially 100 percent SNG. Using this cost for SNG, they then allocated the remaining cost to the gasoline. The result was that the SNG cost 77 percent as much as the gasoline on an energy basis (i.e., it was cheaper on an energy basis to produce SNG solely than to co-produce SNG and gasoline).

Another technique to obtain a representative SNG/gasoline cost relationship is to assume that SNG has the same value as No. 2 fuel oil. This is reasonable since both have at least one large common market in industrial and domestic heating. Using this method, the cost ratio of SNG to gasoline would be the same as that above for No. 2 fuel oil, 0.82.

Since the two techniques yielded very similar results, it was decided to average the two cost ratios. Therefore, the SNG/unleaded gasoline cost ratio used will be 0.80.

These relative product values will not actually be used in this report, since the refining of the H-Coal and SRC-II syncrudes into usable products is beyond the scope of this report. A later study will address the refining of syncrudes and will use these product values to allocate costs appropriately.

III. Process Description and Economic Analysis of the H-Coal and SRC-II Processes

Two general processes have been historically studied to convert coal into liquid fuels. One is indirect liquefaction,

which is essentially coal gasification followed by catalytic reaction of the produced synthesis gas. The second is direct liquefaction which involves direct hydrogenation of coal to form liquids.

Looking at direct liquefaction processes, there are three processes receiving the most consideration today. Two of these direct processes are the Solvent Refined Coal II (SRC-II) and the Exxon Donor Solvent (EDS). Both are considered solvent extraction processes which use coal-derived liquids containing hydroaromatic compounds to transfer hydrogen to the coal, thereby producing liquid hydrocarbons. Unconverted coal, after separation from the extract, may be used to generate the necessary hydrogen. Hydrogen may also be obtained from gases produced during processing, from additional coal, or heavy petroleum products. The third direct liquefaction process is the H-Coal process, which is a catalytic liquefaction technique whereby hydrogen is added to the coal with the aid of a catalyst. This reaction occurs in the liquid phase with particulate catalysts dispersed or present in a fixed bed.[15]

The cost estimates of the products derived from two of these processes will be discussed in detail below. First, a cost analysis of the H-Coal process will be presented, followed by a similar analysis for SRC-II process. A product cost for each of these processes (in terms of dollar per million BTU of product) will be determined from a critique of the studies examining each of these processes. Those product costs best representing each process will then be adjusted according to the common set of economic and financial parameters determined above.

A. The H-Coal Process

The H-Coal process liquifies coal to either boiler fuel or synthetic crude in the presence of an added particulate catalyst. To produce synthetic crude instead of boiler fuel, more hydrogen is added to the slurry and reactor residence times are increased. It was developed by Hydrocarbon Research, Inc. (HRI) and was selected by the Department of Energy for further development on a pilot-plant scale with the participation of Ashland Oil, Mobil Oil, Standard Oil of Indiana, Continental Coal Development Company, the Commonwealth of Kentucky, and Electric Power Research Institute (EPRI). Operation of the pilot plant began in June 1980 with a design capacity of 600 tons per day (TPD) feed coal at Cattlesburg, Kentucky.[10,15]

There are five major studies which analyze the cost of the H-Coal liquefaction process.[2,3,9,10,11] These five studies were performed by Fluor[9], ICF[2], the Engineering Societies Commission on Energy, Inc. (ESCOE)[3], and Ashland Oil (two studies).[10,11] Each study estimates capital costs, operating and maintenance costs, feedstock rate, product mix, and by-product credits.

Each study will be examined in the order described above. After each study has been initially critiqued, the studies will be comparatively critiqued to determine the best single cost estimate. This best cost estimate will then be normalized for size, inflation and economics according to the discussion in Section II above.

1. Fluor[9]

This study was prepared by Fluor Engineers and Constructors, Inc. for the Electric Power Research Institute (EPRI). Fluor obtained field data from Hydrocarbon Research for the technical and economic evaluation of the H-Coal process. Fluor's scope-of-work included development of the overall plant configuration for large commercial facilities to produce hydrocarbon liquids from 14,448 TPD of two different coals, Illinois No. 6 (bituminous) and Wyodak (subbituminous). Actual production from these feed rates were estimated by Fluor to be 43,000 barrels per day (BPD) from the Illinois No. 6 coal, and 35,000 BPD from the Wyodak. The plants were operated in the syncrude mode and employed the latest yield data generated by HRI's process development unit at Trenton, New Jersey at the time the report was written (Dec. 1979).

Fluor prepared detailed material and energy balances for each of the two cases. Each case was designed to be self-sufficient with respect to its internal requirements of hydrogen, fuel, electric power, steam, and other utilities. Hydrogen was produced via the gasification of vacuum bottoms using Texaco technology, while electric power was produced from combined-cycle gas turbines fired by process-derived fuel gas.

In each case, Fluor's work showed that the major products produced included naphtha, turbine oil and distillate fuel oil, while the Illinois case also produced a substantial amount of LPG. The breakdown of products for each case are shown in Table 3. Overall thermal efficiencies (using higher heating values (HHV)) of 68.4 and 60.9 percent were determined by Fluor for the Illinois and Wyodak case, respectively.

Fluor stated that researchers have generally observed that the Wyodak coal is not as favorable to use in the liquefaction process as is the Illinois coal. Although this phenomena is somewhat less observed in the catalytic H-Coal process, use of the Wyodak coal is still considered economically inferior to use of the Illinois No. 6 coal. Fluor stated that this may be related to the higher oxygen content of the coal that reacts to form water, resulting in increased hydrogen consumption. However, although economic considerations for Wyodak coal are not favorable at present, Fluor believed that future commercial developments may occur if conditions are found that favor oxygen removal in the form of carbon monoxide. For purposes of this analysis, then, the Wyodak case will still be presented, though it should be remem-

Table 3

Product Slate of the H-Coal Liquefaction Process
(Barrels Per Day of Fuel Oil Equivalent*)

	Fluor[9]		ICF[2]		ESCOE[3]	Ashland[10,11]
Product	Illinois No. 6 Coal	Wyodak Coal	Illinois No. 6 Coal	Wyodak Coal	Illinois No. 6 Coal	Illinois No. 6 Coal
Feed Rate (Tons/Day)	14,448	14,448	16,370	20,548	25,000	18,000
Naptha	13,392	15,952	15,173	22,700	31,900	
Turbine Oil	16,235	12,366	18,395	17,600		
Distillate Fuel Oil	8,761	6,842	9,926	9,700	24,300	26,300
Butane	3,350	--	3,796	--	--	4,300
Propane	2,392	--	2,710	--	--	6,500
LSR Gasoline	--	--	--	--	--	3,750
Reformate	--	--	--	--	--	11,500
Total	44,130	35,160	50,000	50,000	56,200	52,350
By-Products						
Sulfur (TPD)	493	--	--	--	--	535
Phenols (TPD)	40	--	--	--	--	100
Ammonia (TPD)	165	--	--	--	--	200
Pipeline Gas (MMSCFD)	--	--	--	--	56.3	32
Ethane (MMSCFD)		--	--	--	--	--

* One fuel oil equivalent barrel contains 5.9 million Btu.

bered that it assumes that a number of technological breakthroughs will occur.

The capital cost estimates made by Fluor for an Illinois No. 6 and a Wyodak coal liquefaction plant were determined in mid-1979 dollars. The capital costs for Illinois coal plant was based on an Illinois location on a clear and level site, receiving coal by railway. The capital cost for the Wyodak coal plant assumed that coal would be received via conveyer from a nearby surface mine. The total capital requirement estimated by Fluor included total plant investment, prepaid royalties, preproduction costs, working capital, initial chemical and catalyst charge, allowance for funds during constructions, and land. The total plant investment included process plant investment and general (or offsite) facility costs (excluding contingency). The process plant investment included the total constructed costs of all onsite processing and generating units, including all direct and indirect construction costs and all engineering and home office fees. Taxes (5 percent of total material) were also included.

Fluor's estimates for the total capital costs for both the Illinois and Wyodak coal liquefaction plants are shown in Table 4. The total instantaneous capital cost were estimated to be $1194 million and $1262 million (without a contingency factor) for Illinois and Wyodak coal, respectively. The operating costs as estimated by Fluor were divided into fixed and variable costs, to be estimated on a first year basis. The fixed operating costs included operating labor, maintenance, and overhead charges. The average labor rate was estimated at $12.50 per hour (in mid-1979 dollars). Annual maintenance costs were estimated as a percentage of the installed capital cost of the facilities. Overhead charges included administrative and support labor, and general and administrative expenses. The variable operating costs included the cost of raw water, consumable catalysts and chemicals, and ash disposal. By-product credits included the value of ammonia and raw phenols.

The fixed and variable operating costs for both types of plants are shown in Table 5. The fixed operating cost was estimated to be $66 million and $70 million per year, while the variable operating cost, excluding feedstock, was estimated to be $15 million and $14 million per year for Illinois and Wyodak coal, respectively.

2. ICF[2]

An investigation of the ICF study found that all process cost estimates were taken directly from the Fluor study above. These process costs were then adjusted by ICF to a production of 50,000 barrels per day. ICF used an average scaling factor of 0.830 to adjust capital costs. ICF also adjusted all product costs according to their own financial inputs and assumptions. ICF did not perform any additional research into the process itself.

Table 4

Capital Costs - H-Coal (As Estimated by Fluor[9]
(Mid-1979 Dollars)

	Illinois #6 Coal (million dollars)	Wyodak Coal (million dollars)
Total Plant Investment	904.7	943.3
Prepaid Royalites	3.3	3.6
Preproduction Costs	32.5	34.7
Inventory Capital (Working Capital)	42.7	40.3
Initial Catalysts and Chemicals	6.9	7.3
Allowance for Funds During Construction	201.9	231.7
Land	1.8	1.8
Total Capital Requirement	$1194	$1262

Table 5

Fixed and Variable Operating Costs
(As Estimated by Fluor)[9]
(Mid-1979 Dollars)

Fixed Operating Costs, $Million/Year	Illinois #6 Coal	Wyodak Coal
Operating Labor	9.0	9.0
Maintenance Labor	14.3	15.5
Maintenance Materials	21.4	23.2
Administrative and Support Labor	7.0	7.3
General and Administrative Expense	13.9	14.7
Total Fixed Operating and Maintenance, First Year	65.6	69.7
Variable Operating Costs Excluding Feedstock (First Year), $Million/Year		
Water	1.0	0.9
Catalysts	11.9	12.1
Ash Disposal	2.3	1.4
Total Variable (excluding feedstock)	15.2	14.4

ICF's product slate is shown in Table 3. It is the same as Fluor's product slate, scaled up to a production of 50,000 barrels per day. ICF's capital costs (without contingency) are shown in Table 6. Note that, unlike Fluor, ICF does not include preproduction costs, inventory capital, initial catalyst and chemical costs, allowance for funds during construction and land costs. ICF did not explain the elimination of these costs.

The fixed and variable operating costs are shown in Table 7. All costs are in mid-1980 dollars. According to ICF, the capital cost of an H-Coal plant was estimated to be $1101 million and $1520 million for Illinois and Wyodak coal, respectively. Total operating costs were estimated to be $86.2 million and $91.4 million for Illinois #6 and Wyodak coal, respectively.

3. ESCOE[3]

Similar to ICF, ESCOE also used the Fluor study as a reference for their process cost estimates. In addition, ESCOE derived much of their cost estimates from a 1976 Bureau of Mines report.[16] ESCOE scaled their cost estimates to a feed rate of 25,000 tons of coal per day, which leads to a production of 31,900 BFOE/D naphtha, 24,300 BFOE/D fuel oil, and 56.3 million standard cubic feet per day (mSCF/D) natural gas as shown in Table 3. ESCOE also adjusted costs according to their own financial parameters and according to their specified product values with gasoline as a reference price. ESCOE did not specify what type of coal was used as feed.

ESCOE estimated the capital costs to be $1134 million in 1978 dollars. ESCOE only broke down these capital costs by process unit. Fixed and variable operating cost were estimated to be $103 million and $178 million, respectively. ESCOE did not include other operating costs such as water and ash disposal. ESCOE's cost estimates are shown in Table 8.

4. Ashland Oil[10,11]

Ashland Oil recently released two studies on the commercial H-Coal liquefaction plant which is planned to be built in Breckinridge County, Kentucky (and hence is called the Breckenridge Project). The first study was an in-depth analysis of the technology, economics, and environmental impact of the H-Coal plant (released in March, 1981).[10] The second study was an updated version of the first study, and was presented at an American Petroleum Institute meeting in Chicago on May 13, 1981.[11]

According to the Ashland reports, the Breckinridge Project facilities will be owned by the Breckinridge Energy Company (BEC), a partnership which currently includes Ashland Oil, Inc., through its subsidiary, Ashland Synthetic Fuels, Inc. (ASFI); and Airco Inc., through its subsidiary, Airco Energy Company, Inc. The

Table 6

Capital Costs - H-Coal (As Estimated by ICF)[2]
(Mid-1980 Dollars, Millions of Dollars)

Plant Selection	Illinois No. 6 Coal	Wyodak Coal
Coal Preparation	45	96
Liquefaction	345	464
Light Ends Processing	41	15
Hydrogen Plant	206	304
Oxygen Plant	100	119
Emission Control System	21	17
Effluent Control System	40	34
Storage	48	25
Utilities	156	188
Offsites	94	250
Prepaid Royalties	5	8
Total*	1101	1520

* Does not include contingency.

Table 7

Fixed and Variable Operating Costs for H-Coal
(As Estimated by ICF) (Mid-1980 Dollars)[2]

Fixed Operating Costs, $Million/Year	Illinois #6 Coal	Wyodak Coal
Operating Labor	8.2	8.2
Overhead	22.6	24.0
Maintenance	38.6	41.9
Total, First Year	69.4	74.1
Variable		
Water	1.2	1.3
Power	0	0
Catalysts and Chemicals	14.7	17.3
Ash Disposal	0.9	0
Total (excluding feedstock)	16.8	17.3

Table 8

Fixed and Variable Operating Costs for H-Coal
(As estimated by ESCOE) (Mid-1978 Dollars)[3]

Capital Cost	Illinois No. 6
Plant Capital Requirements	
Coal Preparation	484
H_2 or Gasification	158
O_2 Plant	87
Gas Shift	35
Acid Gas and Sulfur Plants	57
Reactor Section	210
Gas Plant	25
Pollution Control	40
Total	696
Other	438
Total Capital Cost	1134
Fixed Operating Costs ($ Millions/Year)	
Labor	12.2
Maintenance	34.3
Local Tax and Insurance	57.0
Total, First Year	103.5
Variable	
Catalyst and Chemicals	7.0
Total	7.0

venture will eventually be expanded to at least five partners. Under the partnership agreement, and consistent with the policy followed during the initial effort, ASFI will be the operator with responsibility for managing detailed engineering, procurement, construction, and operations.

The plant is to be located on the Ohio River near Addison, in western Kentucky. Work that is currently underway at the location includes soil survey work, baseline environmental data collection, and socioeconomic studies. According to Ashland, preliminary studies indicate that no serious environmental or socio-economic problems exist. Ashland stated that discussions with local and state officials make it clear that support from these groups is strong. Construction of the commercial plant was projected by Ashland to begin in 1983. Ashland estimated that by 1988 construction should be completed followed by efforts for plant startup. The plant was projected to be operating at full capacity in 1991.

In its base case configuration Ashland designed the plant to operate on 18,000 TPD of washed Illinois no. 6 coal and other various Illinois Basin coals. The product slate is shown in Table 3. The LSR gasoline and reformate are already refined products, while the rest of the product slate must undergo further refining. The production of by-products include 100 TPD of phenols, 200 TPD of ammonia, 535 TPD of sulfur, 32 mSCF/D of pipeline gas, and 8 mSCF/D of ethane. Alternative product slates presently being evaluated by Ashland would provide for the additional production of benzene, toluene, and xylene. The thermal efficiency of the process was estimated to be 63.1 percent.[17]

In their first study, Ashland's design efforts included extensive use of computer simulations based upon experimental data and has produced what they believe to be the most accurate information on the Breckenridge project presently available. Ashland presented costs based on estimates completed in 1980, which were then adjusted to 1981 dollars according the Gross National Product (GNP) deflator. In their second study, Ashland determined costs directly in 1981 dollars based on more recent process data. Because the costs in the second study represent more recent estimates and are based on the most recent data, these costs will be presented below instead of those from the first study.

Total instantaneous plant capital cost was estimated by Ashland to be $3.3 billion. Ashland included in this cost a contingency for construction costs overruns of approximately 15 percent plus a provision for working capital. A summary of the project capital cost is shown in Table 9.

This capital cost included the cost of a reformer to refine light naphtha to reformate. This cost has not been included in

Table 9

Total Project Costs
(As estimated by Ashland) (January, 1981 Dollars)[11]

	$Million
Direct Costs:	
Liquefaction Plant	690
Oxygen and Hydrogen Plants	320
Other Refinery Units	125
Tankage, Interconnecting Piping	120
Coal Handling, Boilers	360
Wastewater/Solids Treating	200
Other Offsites	185
Total	2000
Field Indirects	400
Miscellaneous Field Costs	80
Engineering and Fee	280
Contingency	400
Total Installed Cost	3160
Working Capital	140
Total Project Cost	3300

the other previous studies (Fluor, ICF, and ESCOE). (A later report will consider the cost of refining syncrudes and will consider the degree to which the various synthetic petroleum fractions have been refined at the liquefaction plant.) A breakdown of the cost of the general processing units is also shown in Table 9.

Total annual operating costs were estimated to be $126 million and are summarized in Table 10. Excluded by Ashland from the annual operating costs are the coal feedstock costs and the capital recovery charges.

5. Adjustment and Comparison of Each Study

The costs presented in each of the four H-Coal analyses will be adjusted in this section to the common plant size and financial parameters as discussed in section II above. For convenience, capital costs will be left as instantaneous costs until the most representative study is selected. Coal costs and by-product credits will also not be included until later.

Once each of the above four analyses have been adjusted, the most representative study will be determined. This selected best study will then be adjusted for lifetime capital costs and calendar day operations, with feedstock costs and by-product credits also included. A product cost will then be determined for this selected study. The capital and operating costs, as originally estimated by each study, are summarized for convenience in Table 11.

The adjusted product slates and costs for each study are shown in Table 12 and 13, respectively. With respect to the Fluor study, instantaneous capital costs were adjusted with a scaling factor of 0.75 and a 15 percent contingency. Labor costs were adjusted with a scaling factor of 0.2. Water, catalyst, and ash disposal costs were adjusted proportionally to plant size. Working capital was estimated at 6 percent of operating and maintenance costs. Remaining costs were assumed to be the same percentage of plant investment for each plant size. All costs were inflated from 1979 to 1981 dollars.

Since the costs estimated by ICF already presumed a producton of 50,000 BFOE/D, their costs did not have to be adjusted for plant size. Only a 15 percent contingency was incorporated along with inflation from 1980 to 1981 dollars. Also, in determinig maintenance labor costs it was assumed that maintenance labor was 40 percent of total maintenance costs, the same percentage used in the Fluor study.

ESCOE's cost estimates had to be scaled down from a production of 56,200 BPD/FOE to the desired production of 50,000 BPD/FOE. The scaling factors described in Section II were used

Table 10

Annual Operating Costs[11]
(January, 1981 Dollars)

Power Annual Catalyst and Chemicals	$ 4,623,500
Direct Labor and Supervision	10,697,800
Plant Maintenance (Includes Labor, Supervision, Materials and Contractor Maintenance)	43,935,400
Payroll Overhead and Operating Supplies	12,515,100
Indirects, G&A	7,016,700
Local Taxes and Insurance	47,511,500
Total*	126,300,000

* Includes a 15 percent contingency.

Table 11

Summary of H-Coal Capital and Operating Costs,
As Estimated by Each Study

	EPRI		ICF		ESCOE	Ashland
Coal Type	Illinois No. 6 Coal	Wyodak Coal	Illinois No. 6 Coal	Wyodak Coal	Illinois No. 6 Coal	Illinois No. 6 Coal
Year	Mid-1979	Mid-1979	Mid-1980	Mid-1980	Mid-1978	1st Q 1981
Thermal Efficiency	68.4%	60.9%	68.4%	60.9%	NA	63.1%
Total Production (BPD/FOE)	44,130	35,160	50,000	50,000	56,200	52,350
Capital Cost ($Million)						
Plant	905	943	846	1074	696	2000
Other	289	319	255	446	438	1300
Operating Costs ($Million/Yr)*						
Fixed	65.6	69.7	69.4	74.1	103.5	121.7
Variable	15.2	14.4	16.8	17.3	7.0	4.6

* Excludes feedstock costs.

Table 12

Adjusted H-Coal Product Slates
Based on 50,000 BPD/FOE Commerical Plant Size

Product BPD/FOE	EPRI Illinois No. 6 Coal	EPRI Wyodak Coal	ICF Illinois No. 6 Coal	ICF Wyodak Coal	ESCOE	Ashland Illinois No. 6 Coal
Naptha	15,173	22,685	15,173	22,700	28,380	
Turbine Oil	18,395	17,585	18,395	17,600	--	
Distillate Fuel Oil	9,926	9,730	9,926	9,700	21,620	26,300
Butane	3,796	--	3,796	--	--	4,300
Propane	2,710	--	2,710	--	--	6,500
LSR Gasoline	--	--	--	--	--	3,750
Reformate	--	--	--	--	--	11,500
Total	50,000	50,000	50,000	50,000	50,000	50,000
By-Products (TPD)						
Sulfur	559	58	559	58	N/A	535
Phenols	45	23	45	23	N/A	100
Ammonia	187	166	187	166	N/A	200
Pipeline Gas (MMSCFD)	--	--	--	--	56	32
Ethane (MMSCFD)	--	--	--	--	--	8

Table 13

Adjusted H-Coal Cost Estimates
Based on 50,000 BPD/FOE Commerical Plant Size

	EPRI		ICF			Ashland
	Illinois No. 6 Coal	Wyodak Coal	Illinois No. 6 Coal	Wyodak Coal	ESCOE	Illinois No. 6 Coal
Capital Costs ($Millions of 1981 Dollars)						
Plant Investments	1,180	1,459	922	1,171	811	1,740
Other	382	494	288	486	510	1,130
Contingency	234	293	180	248	198	430
Total	1,796	2,246	1,380	1,906	1,519	3,300
Operating Costs ($Millions of 1981 Dollars)						
Fixed						
Operating Labor & Maintenance Labor	30.4	31.2	25.8	27.2	32.2	28.3
Other	55.2	69.9	49.9	53.6	82.4	93.4
Variable						
Water, Catalyst, etc.	20.5	20.5	18.3	18.9	7.9	4.6
Working Capital	6.4	7.3	5.6	6.0	7.4	7.6
Total	112.5	128.9	99.6	105.7	129.9	133.9
Coal Feed Rate	16,370	20,550	16,370	20,550	22,242	18,000

with a 15 percent contingency on capital costs. Maintenance labor was also estimated at 40 percent of total maintenance cost.

The total production in the Ashland studies is very close to the desired production rate of 50,000 BFOE/D and, for purposes of this study, will not be modified. Also, all of Ashland's costs were already in 1981 dollars and included a 15 percent contingency, so they required no further adjustment.

Of the above four sets of studies, ICF and ESCOE did not perform their own engineering cost estimates. ICF based all their process cost estimates on the Fluor estimates, while ESCOE incorporated some of Fluor's work along with a Bureau of Mine study into their overall cost estimate. Thus, the ICF and ESCOE studies will not be assessed at this point until the firsthand studies of Fluor and Ashland are further analyzed.

Both Fluor's and Ashland's estimates will be briefly reviewed here. In the Fluor study, two types of coal feeds were considered, Illinois No. 6 coal and Wyodak coal, while Ashland only considered costs for Illinois No. 6 coal as feed. Of the two sets of studies, the Ashland analyses should represent the most accurate process costs of H-Coal liquefaction, primarily because the Ashland studies are more recent (1981). Although the Fluor study is fairly recent (1979), the projected technology and costs have changed dramatically even within two years (i.e., from 1979-1981). Costs associated with the updated technological and process developments have escalated much more rapidly than inflation as indicated by the differences in the costs shown in Tables 4 and 9. The Ashland estimates will be selected as the more representative of the two.

The ICF and ESCOE studies should also be eliminated from further consideration for the same reason. The ICF study was based on the Fluor estimates which are now out of date. ESCOE's cost estimates were based on Fluor's estimates and an even older 1976 Bureau of Mines report with costs simply inflated to the year of ESCOE's study, or 1978.

Because the Fluor estimates for the Illinois coal case were eliminated above due to outdated cost information, their estimates for the Wyodak coal case should also be eliminated for the same reason. However since Ashland has not examined Wyodak coal as a feed, there would appear to be no up-to-date estimate of H-coal process costs for Wyodak coal. The only thing that can be said at this time is that it is likely that the processing of Wyodak coal would be more expensive and less efficient than Illinois coal, based on the Fluor results.

An overall product cost will now be estimated for the H-Coal process based on the Ashland estimates. The instantaneous capital cost and operating costs have already been determined in Table

13. To obtain the annual capital charge, the interest during construction and the capital charge rate must be applied to the instantaneous capital cost. The result of this for each financial scenario is shown in Table 14, along with the previously determined operating costs.

The feedstock rate has already been determined to be 18,000 TPD, which amounts to 5,940,000 tons per year, based on 365 day per year operation. At a coal price of $27.50 per ton, the total annual feedstock cost would be $181 million per year. The annual by-product credit is based on a value of $50 per ton for sulfur, $180 per ton for ammonia, and $113 per barrel of phenol. Based on the rates of production presented above (see Table 12), total annual by-product credit is $13 million per year. Pipeline gas (SNG) and ethane will be considered products and will be included in the total energy output of the plant.

The total annual cost is the sum of the annual capital, operating, and feedstock costs, less the by-product credits. This amounts to $1402 million per year for the high capital charge rate case and $732 million per year for the low capital charge rate case.

The energy value of the product is estimated to be approximately 122,275,000 million BTU per year, based on a 50,000 FOEB/D (5.9 million BTU per FOEB) plus the SNG and ethane. The total product cost is then $11.47 per million BTU for the high capital charge rate case and $5.99 per million BTU for the low capital charge rate case.

B. The SRC-II Process

The SRC process is being developed by Pittsburg and Midway Coal Mining Company, a subsidiary of Gulf Oil Corporation, under DOE sponsorship. The SRC II process converts coal to liquid and gaseous products by dissolving finely-ground coal and mixing it with recycled process solvent. Hydrogenating and hydrocracking of the dissolved coal takes place at an elevated temperature and pressure. Catalytic activity in recycle slurry enhances hydrogenation and hydrocracking. Inorganic matter in the feed coal also accelerates these reactions.[15,18]

In the process, raw coal is ground to fine particles and is then mixed with hot-recycle slurry in a mix tank. This mixture of coal and recycle slurry is pumped together with hydrogen through a fine preheater to a reactor maintained at about 460°C (860° F) and 2000 psig. Upon exiting the preheater, the pulverized coal is almost completely dissolved in the solvent portion of the recycle slurry. Highly exothermic hydrocracking reactions occur in the reactor, allowing the temperature at the outlet of the preheater to be considerably lower than the required reactor temperature. Hydrogen is injected into the reactor for temperature control and

Table 14

Overall Product Cost of the H-Coal Process Based on Ashland Estimates ($1981)

	Low Cost Case	High Cost Case
Instantaneous Capital Cost ($Billion)	3.3	3.3
Annual Capital Charge (millions per year)	430	1100
Operating Costs (millions per year)	134	134
Feedstock Cost (millions per year)	181	181
By-Product Credit (millions per year)	(13)	(13)
Total Annual Cost (millions per year)	732	1402
Average Product Cost (per mBtu)	5.99	11.47

to maintain adequate gas distribution, as well as to promote the hydrocracking reactions. The reactor effluent flows through a series of vapor-liquid separators, where it is ultimately separated into process gas, light hydrocarbon liquids and slurry.

The process gas consists primarily of hydrogen and gaseous hydrocarbons, together with minor amounts of hydrogen sulfide and carbon dioxide. It is cooled to about 38° C (100° F) and goes through an acid gas removal step for removal of hydrogen sulfide and carbon dioxide. The treated gas passes through a cryogenic separation step for removal of the hydrocarbons. The purified hydrogen is recycled to the process, while the hydrocarbons are recovered as products.

Any remaining carbon monoxide is converted to methane and is then sold as pipeline gas (SNG). The other light hydrocarbon gases are fractionated to produce ethane, propane, and butane streams. All of the light hydrocarbon liquid collected from the various condensation steps, plus the overhead stream from the vacuum tower (below) are sent to the fractionator. In the fractionator, the total liquid product is separated into naphtha, middle distillate, and heavy distillate.

The product slurry is split, with one portion being recycled to the process for slurrying with the feed coal. The other portion of the product slurry goes to a vacuum tower where the lighter portion of the distillate is removed overhead and sent to the fractionator. A heavy distillate product is removed as a sidestream. Residue from the vacuum tower is converted into synthesis via gasification gas. A portion of this gas is used to produce hydrogen for the process. The synthesis gas in excess of that required for hydrogen production is purified and burned as a plant fuel.

There are six major studies which specifically analyze the costs of the SRC-II liquefaction process. These studies include two by Pittsburg and Midway Coal Mining Co., one by Ralph M. Parsons Co., an ICF study, an ESCOE study and a recent DOE study. Each study estimates a final product cost (in terms of dollars per million BTU) based on capital costs, operating and maintenance costs, feedstock costs, and by-product credits.

First, the two Pittsburg and Midway Coal studies will be examined, followed by the Parsons study, the ICF report, the ESCOE report and the DOE report. After these studies have been critiqued and partially adjusted for comparison purposes, the study with the most accurate estimates will be selected. As was done with the H-Coal process, cost estimates from the selected study will be adjusted according to all of the input factors determined in section II. A final product cost will then be estimated.

1. Pittsburg and Midway Coal Mining Company[12,18]

Two studies of the SRC-II process were recently completed by Pittsburg and Midway Coal Mining. The first study, performed under contract with DOE, was a 1979 study which gave a detailed analysis of the SRC-II Conceptual Commercial Plant.[12] Pittsburg and Midway stated that the Conceptual Commercial Plant produces a product slate including SNG, butane LPG, low sulfur fuel oil, an ethane-propane light hydrocarbon stream and a naphtha stream, as well as sulfur, ammonia, and tar acid by-products. The ethane-propane light hydrocarbon stream and the naphtha stream could both be burned directly as fuel products. However, Pittsburg and Midway stated that they are both readily capable of being upgraded to higher valued products by known technology. A detailed economic analysis was also included in this study by Pittsburg and Midway, with capital costs and annual operating and maintenance expenses.

The second study,[18] completed in 1980, was essentially an updated version of the first study, and although it was not as detailed, it still addressed the areas of importance for purposes of this study. The cost estimates of the second study will be used here except where they are not addressed. In these cases, the costs from the more detailed first study will be used.

The economic analysis for a commercial-size plant completed by Pittsburg and Midway mining was based on work prepared for the 6,000 ton per day demonstration plant which to be located near Morgantown, West Virginia. This commercial-size plant would process West Virginia area coal (Powhaten Coal, 12,813 BTUs per pound) at a rate of 33,500 tons per stream day (330 days per year). Pittsburg and Midway estimated the thermal efficiency of the process to be 72 percent, producing the product slate shown in Table 15. On an energy basis, this amounts to a total production of 100,000 BFOE/D.

The investment and operating costs for the conceptual commercial plant as estimated by Pittsburg and Midway mining were based on a design developed by assuming that the key process steps will be successfully demonstrated in the mid-1980's in the 6,000 T/D demonstration plant, and that the first commercial plants will be built and operating in the early 1990's. The direct capital cost estimates were those costs which would normally be incurred for engineering, procurement, and construction. They included direct field costs, indirect field costs, and engineering costs. The indirect capital cost estimates included catalyst and chemicals, license, owner management costs, land, and working capital.

Indirect field costs included field staff costs, field office expenses, payroll taxes, insurance, performance bonds, consumable supplies, temporary facilities, construction equipment rental, and small tools. No precommissioning or commisioning costs have been included.

Table 15

Product Slate of the SRC-II Liquefaction Process
(Barrels Per Day of Fuel Oil Equivalent

Product	Pittsburg and Midway[13]	Parsons[14]	ESCOE[3]	ICF[2]	DOE[22]
Naptha	17,000	5,148	10,700	8,700	3,050
Fuel Oil	56,000	11,253	45,300	36,800	10,030
Residual	--	33,680	--	--	--
LPG (Ethane/ Propane)	22,000	--	5,500	4,500	3,900
Butane	3,000	--	--	--	500
Methane (MMSCFD)	50	--	--	--	10
Total	100,000	50,000	61,500	50,000	18,000
By-Product (TPD)					
Sulfur	1,200	N/A	854	694	215
Ammonia	180	N/A	283	230	30
Phenols	--	N/A	69	56	--
Tar Acids (BPD)	240	N/A	--	--	43
Feed Rate (TPD)	33,500	17,232	25,000	20,325	6,000

Engineering costs were estimated as a percentage of total field costs (the sum of direct and indirect field costs). The total estimate included approximately 3,964,000 engineering hours for the engineering/construction contracter.

The total instantaneous direct capital investment, including a 20 percent contingency, was $1794 million in 1st quarter 1980 dollars. A breakdown of these costs are shown in Table 16. The total indirect investment is $190 million.

The total instantaneous capital costs were then $1.98 billion, based on a production of 100,000 barrels of fuel oil equivalent per day.

The annual operating costs (fixed and variable) were estimated with appropriate contingencies included, in accordance with DOE guidelines. The operating labor and supplies included an average operator rate plus adjustment for idle time, fringe benefits, and contingency. Operating supplies were calculated at 10 percent of operating labor. Maintenance labor were also included in operating costs, based also on an average rate for maintenance work, plus adjustments for idle time, fringe benefits and contingency. Maintenance materials were assumed to be 2 percent of total depreciable investment including catalysts and chemicals and owner management costs but excluding license fees and land. Contract maintenance was also estimated in this cost at the same number of workers as the direct-fire plant maintenance work force. Catalysts chemicals, and electricity (at $0.035 per KWH), and property taxes and insurance (at 1.5 percent of fixed capital investment) were also included in the operating costs. The total annual operating costs, without feedstock, was estimated to be $110 million per year (1980 dollars).

In summary, the total instantaneous capital cost were estimated to be $1.98 billion and the total operating cost were estimated to be $110 million, without feedstock in 1980 dollars. These cost estimates will be compared later to the remaining four studies below (Parsons, ICF, ESCOE and DOE).

2. Parsons[19]

A study sponsored by EPRI was prepared by The Ralph M. Parsons Company of Pasadena, California. In this study, two cases were developed for the SRC-II process: a case to represent normal operations required to maximize the production of heavy fuel oil and a case at more severe operating conditions to lower the sulfur content of the products and increase the yield of liquid fuel products (i.e., in the syncrude mode). For purposes of this analysis, only the case where the low sulfur content is produced will be considered. This case produces a crude more similar to petroleum than the first case which can be later refined to a usable transportation fuel.

Table 16

Capital Investments for SRC-II (As Estimated by Pittsburg and Midway Coal Mining Company)[13]

33,500 T/SD
West Virgina Coal

	Millions of Dollars (First Quarter 1980)
Coal and Ash Handling	86
Hydrogenation	707
Hydrogen Production	480
Refining and Gas Recovery	161
Secondary Recovery	94
Utilities and General Facilities	266
Total Direct Investment	1794
Indirect Investment	190
Total	$1984

A factored cost estimate was prepared by Parsons in the EPRI study. For process units that were under pilot plant development, major equipment was sized and factored to an installed cost. Process units that were commercially demonstrated were factored from previously developed cost estimates. The estimates assumed a complete, self-sustaining plant which included the generation of all power required for their operation. The plant capacities were based on a normal output of 50,000 BFOE/D.

The products in this study were based on an experimentally achieved 69.9 percent overall thermal efficiency. The products were 33,680 BPD of residual oil, 11,253 BPD of fuel oil, and 5,148 BPD of naptha. The coal feed rate was 17,232 tons per day. These are shown in Table 15.

The total capital costs as estimated by Parsons are shown in Table 17. The total capital costs were defined as the sum of total plant investment, royalty allowance, preproduction costs, working capital, construction loan interest, capital cost escalation and land. The total plant investment was the sum of total constructed cost, home office engineering and overhead, contingency and sales tax. These costs are mid-1976 estimates.

The home office engineering and overheads were estimated at nominally 15 percent of total constructed costs based on Parsons experience. This charge covered the cost of management and administrative, process and project engineering, construction support, design, drafting, accounting, estimating, scheduling, cost engineering, procurement, expediting, inspection, stenographic and clerical expense, printing, reproduction, computer charges, communications and travel.

Contingency was also included in the capital costs, estimated to be 15 percent of the sum of total constructed costs and home office engineering and overhead. Sales tax were estimated at 5 percent of direct material costs. Royalty allowance was arbitrarily taken at 0.5 percent of total plant investment. Land requirements were estimated at two sections (1280 acreas) which presumably could be purchased for $2,500/acre. The total instantaneous capital cost was estimated to be $1.61 billion (1976 dollars).

The annual operating costs were also calculated by Parsons based on a 90 percent onstream factor, and are shown in Table 18. The total direct operating costs included washed coal, residue disposal, raw water, catalyst and chemical, operating labor requirements, and maintenance labor and materials. The total annual direct costs were estimated to be $57 million (1976 dollars) without the cost of feedstock. The indirect costs include administrative and support labor, general and administrative expenses, and property tax and insurance. The total

Table 17

SRC-II Capital Cost Estimates
(As Estimated by Parsons)[14] Mid-1976
($Million)

Total Constructed Cost:	867
Home Office Engineering	130
Contingency	150
Sales Tax	26
Total Plant Investment:	1173
Royalty Allowance	6
Preproduction Costs	76
Working Capital	85
Construction Loan Interest	269
Capital Cost Escalation	0
Land	3
Total Capital Requirement	$1612

Table 18

SRC-II Annual Operating Cost, Excluding Feedstock
(As Estimated by Parsons)[14]

Direct Costs	(Millions of 1976 Dollars)
Residue Disposal	0.869
Water	1.314
Catalyst and Chemicals	17.500
Operating Labor	18.528
Maintenance Labor and Materials	18.499
Total Direct Costs	56.710
Indirect Costs	
Administrative and Support Labor	5.558
General and Administrative Expense	11.116
Property Taxes and Insurance	29.336
Total Operating Cost	102.72

indirect expenses are $46 million. The total annual operating costs are then $103 million (1976 dollars), without feedstock costs.

3. ESCOE[3]

ESCOE's cost data was obtained directly from a process developer. However, ESCOE did not mention who the developer was and they merely present the data without explanation. ESCOE's costs were based on a coal feed rate of 25,000 tons of coal per day, and which resulted in a production of 61,500 BFOE/D. The product mix is shown in Table 15.

Although ESCOE did not go into great depth about how their cost estimates were obtained, they did nevertheless present estimates for capital and operating costs (in 1978 dollars). The instantaneous capital cost was $1.26 billion. Annual operating costs (except for feedstock) amounted to $6.0 million for catalysts and chemical, $12.2 million for labor, $38.2 million for maintenance, and $63 million for local tax and insurance. Total annual operating costs were $119 million. These costs are shown in Table 19.

4. ICF[2]

The ICF report based their cost esimates on the ESCOE study just analyzed above, adjusted to ICF's own financial parameters and a production volume of 50,000 BPD. ICF used a average scaling factor of 0.830 to adjust capital costs. They did not perform any additional research into the actual process. The product slate of ICF is shown in Table 15 and the capital and operating costs are shown in Table 20.

5. DOE[20]

DOE has released a very recent cost estimate for the 6,000 TPD demonstration plant located near Morgantown, West Virginia which was being planned cooperatively with Pittsburg and Midway Mining. These updated cost estimates were provided to the Senate Committee on Appropriations, Subcommittee on Interior and Related Agencies following the March 25, 1981 testimony of Roger W. A. Le Gassie, DOE's Acting Assistant Secretary for Fossil Energy.

This release by DOE was very brief and did not go into detail about the SRC-II demonstration plant project. However, much of the technical analyses and results found in the Pittsburg and Midway studies should also apply here relative to the plant size and product slate. Other parameters, such as coal type, should also be identical in both cases.

The breakdown of capital and operating costs (in 1st-quarter 1981 dollars) is shown in Table 21. Capital costs total $1.99

Table 19

Capital and Operating Costs for SRC-II
(As Estimated by ESCOE) (Mid-1978 Dollars)[3]

Capital Cost	Cost (Million Dollars Per Year)
Plant Capital Requirements	
Coal Preparation	63
H_2 or Gasification	253
O_2 Plant	129
Gas Shift	-
Acid Gas and Sulfur Plants	60
Reactor Section	195
Gas Plant	30
Pollution Control	44
Total	774
Other	488
Total Capital Cost	1262
Fixed Operating Costs ($ Millions/Year)	
Labor	12.2
Maintenance	38.2
Local Tax and Insurance	53.0
Total, First Year	113.4
Variable	
Catalyst and Chemicals	6.0
Total	6.0

Table 20

Capital and Operating Costs for SRC-II
(As Estimated by ICF, Mid-1980 Dollars)

Capital Costs	Cost
Plant Selection	
Coal Preparation	63
Reaction Section	195
Light Ends Processing	30
Hydrogen Plant	254
Oxygen Plant	129
Emission Plus Effluent Control System	104
Storage	36
Total Plant Investment	775
Utilities	369
Offsites	109
Prepaid Royalties	7
Total	1260
Fixed Operating Costs ($Million/Year)	
Operating Labor	9.7
Overhead	26.6
Maintenance	45.4
Total, First Year	81.7
Variable	
Water	1.32
Catalyst and Chemicals	5.78
Ash Disposal	1.20
Total (Excluding Feedstock)	8.3

Table 21

Cost Estimates for the 6000TPD
SRCII Demonstration Plant
(February, 1981 Dollars)

	Million Dollars
Phase I - Design (1980-84)	292
Phase II - Construction (1982-86)	1415
Phase IIIA - Start-Up (1986)	286
Preoperational Subtotal	1993
Phase IIIB - 2 Yrs. Operation (1986-88)	347
Phase IIIC - 3 Yrs. Operation (1988-91)	495
Total	842
Annual Average	160

billion, which includes an estimated 13 percent contingency, but no working capital. These costs were given for different phases of the plant development, thus being presented as lifetime costs rather than instantaneous investments. Mechanical operation was estimated to begin in early 1986. The annual operating and maintenance cost was approximately $165 million per year. This did not include coal costs or capital recovery.

6. Selection of Best Study

A summary of the capital and operating costs as estimated by each study are shown in Table 22. Each of these five sets of estimates will be adjusted to an output of 50,000 BFOE/D and the financial input factors discussed in section II above. As was done previously with the H-Coal process, costs at this point will be left as instantaneous capital costs and stream day operations for convenience, unless otherwise specified. Feedstock costs and by-product credits will also be accounted for later. Once selection of the best study or studies have been determined, final adjustments will be made, if necessary, for lifetime capital costs, calendar day operations, feedstock costs, and by-product credits.

The Pittsburg and Midway studies will be examined first. Its adjusted product slate, shown in Table 23, is simply one-half the amount estimated for a 100,000 BFOE/D product slate. The capital cost estimates need to be adjusted to a production of 50,000 BFOE/D using the 0.75 scaling factor, inflated to 1981 dollars and have a 15 percent contingency added. These changes reduce this cost to $1.23 billion (1981 dollars). Labor costs are similarly adjusted using a scaling factor of 0.2. The catalyst, chemical, and electricity costs, originally estimated at $11 million (1980 dollars) for the 100,000 BFOE/D case, would be (with inflation) $6.0 million (1981 dollars) for a production of 50,000 BFOE/D. The remaining operating and maintenance costs are assumed to be the same percentage of plant investment in both the 100,000 BPD/FOE case and the 50,000 BPD/FOE case. A summary of Pittsburg and Midway's adjusted capital and operating and maintenance costs are shown in Table 24.

The Parsons' study is already based on a 50,000 BFOE/D production. Thus, its product slate and process costs will not have to be modified at this point, except for inflation. The inflated costs are shown in Table 24.

The capital costs and operating costs of the ESCOE study required adjustment from ESCOE's original production of 61,500 BPD/FOE to 50,000 BPD/FOE, based on appropriate scaling factors and inflation to 1981 dollars. ESCOE's adjusted costs are shown in Table 24.

Table 22

Summary of SRC-II Capital and Operating Costs,
As Estimated by Each Study

	Pittsburg and Midway[13]	EPRI[14]	ESCOE[3]	ICF[2]	DOE[22]
Coal Type	W.V. Coal	Ill. #6*	Ill. #6*	Ill. #6	W.V. Coal
Thermal Efficiency (%)	72	69.9	N/A	N/A	72
Total Production (BPD/FOE)	100,000	50,000	61,500	50,000	18,000
Capital Cost ($Million/Yr)					
Plant	1,794	1,173	774	775	1,707**
Other	190	439	488	485	286
Operating Costs					
Fixed	99	102.7	113.4	81.7	130
Variable	11	18.5	6.0	8.3	30

* This was assumed for each study where coal types were not stated.

** These are lifetime capital costs.

Table 23

Adjusted SRC-II Product Slates
Based on 50,000 BPD/FOE Commercial Plant Size

	Pittsburg and Midway	EPRI	ESCOE	ICF	DOE
Coal Feed Rate	16,750	17,232	20,325	20,325	16,750
Efficiency (%)	72%	69.9%	70%	70%	72%
Product					
Naptha	8,500	5,148	8,700	8,700	8,500
Fuel Oil	28,000	11,253	36,830	36,800	28,000
Residual	--	33,680	4,470	4,500	--
LPG (Ethane/ Propane)	11,000	--	--	--	11,000
Butane (TPD)	1,500	--	--	--	1,500
Methane (MMSCFD)	25	--	--	--	25
Total	50,000	50,000	50,000	50,000	50,000
By-Product					
Sulfur (TPD)	600	N/A	694	694	600
Ammonia (TPD)	90	N/A	230	230	90
Phenols (TPD)	--	N/A	56	56	--
Tar Acids (BPD)	120	N/A	--	--	120

Table 24

Adjusted SRC-II Cost Estimates,
Based on 50,000 BPD/FOE Commercial Plant Size

	Pittsburg and Midway	EPRI	ESCOE	ICF	DOE
Instantaneous Capital Costs (Millions of 1981 Dollars)					
Plant Investment	969	1,379	787	845	2,870
Other	103	592	496	529	100
Contingency (@ 15%)	161	296	192	206	430
Total	1,233	2,267	1,475	1,580	3,400
Operating Costs (Millions of 1981 Dollars per Stream Day)					
Fixed					
Operating Labor and Maintenance Labor	27.0	13.9	31.3	30.4	62
Other	46.5	73.0	87.4	58.7	218
Variables					
Water, Catalyst, etc.	6.0	26.5	5.8	9.0	47
Working Capital	*	6.8	7.5	5.9	19
Total	79.5**	120.2	132.0	104.0	346

* Included in other costs.

** Calendar day operation.

Concerning the ICF study, product slates and costs are already determined for a production of 50,000 BFOE/D. ICF's costs, however, still must be inflated to 1981 dollars. These costs are shown in Table 24.

Finally, DOE's estimates for lifetime capital costs and operating costs will be adjusted using the appropriate scaling factors. Only a feedrate of 6000 TPD is given by DOE, without the corresponding production volumes. However, both feedrate and production volume should be proportional to the Pittsburg and Midways estimates. Since Pittsburg and Midway estimated a feed rate of 33,500 TPD for a 100,000 BFOE/D plant, 16,750 TPD of coal should correspond to a production of 50,000 BFOE/D. Thus, based on a feedrate of 17,000 TPD and a scaling factor of 0.75, the lifetime capital costs would be $4.35 billion, which includes a 13 percent contingency but does not include working capital. With a 15 percent contingency and working capital, which is estimated to be about 4 percent of all other capital costs (based on the previous studies), the total lifetime cost would be $4.60 billion.

The instantaneous capital cost of the DOE study will now be estimated so that it can be compared to the instantaneous capital costs of the other studies. The instantaneous capital cost depends on the construction interest rate and the building schedule incorporated into DOE's lifetime capital cost. The investment schedule is shown in Table 25, and the opportunity cost, based on DOE's work, is estimated to be 10 percent per year. The resulting adjustment factor is 1.348. If the lifetime capital cost of $4.60 billion is divided by the adjustment factor of 1.348, the resulting instantaneous capital cost is $3.4 billion.

As mentioned earlier, DOE estimated total operating costs to be $165 million per year. Adjusting this cost to the desired plant size of 50,000 BFOE/D is difficult since DOE did not give a complete breakdown of the labor, catalyst, chemical, electricity and other costs. However, based on the Pittsburg and Midway studies, the labor costs for the 6000 TPD plant are 30 percent of total annual operating costs, or $50 million. When adjusted to a plant size of 50,000 BFOE/D production, the labor cost is about $62 million, based on a 0.2 scaling factor. Pittsburg and Midway estimated catalyst, chemical, and electricity costs to be about 10 percent of the annual operating costs, which would be $16.5 million for the 6000 TPD plant. Since these vary in direct proportion to plant size, these costs would total $47 million for the 50,000 BFOE/D plant. The remaining operating and maintenance costs (excluding working capital interest) are 60 percent of total operating and maintenance costs, or $100 million. These costs are based on a fixed percentage of capital and, based on a 0.75 scaling factor, would amount to $218 million for the larger plant. This would bring the total operating and maintenance cost, without working capital interest, to $315 million per year. With working

Table 25

Investment Adjustment Factor Calculations
For DOE-SRC-II Study

Year	Fraction of Investment Completed	Adjustment for During Design, Construction, and Start-up	Adjustment Factors
1980	0.029	$(1.10)^7$	0.057
1981	0.029	$(1.10)^6$	0.051
1982	0.171	$(1.10)^5$	0.275
1983	0.171	$(1.10)^4$	0.250
1984	0.171	$(1.10)^3$	0.228
1985	0.142	$(1.10)^2$	0.172
1986	0.286	$(1.10)^1$	0.315
	1.00		1.348

capital interest at 6 percent of this cost, the total operating and maintenance costs amount to $346 million per year. As with the other studies, feedstock costs and by-product credits will not be estimated until later.

The ESCOE and ICF studies will be evaluated first, primarily because ICF depends upon ESCOE's study and thus the outcomes of these two studies should be similar. ESCOE expresses their own judged accuracy in their cost estimate in what is known as a "confidence factor." The "confidence factor" for this process development is described as "pre-commercial successful pilot plant operation." However, the economic reliability is described as "screening estimate, very approximate." ESCOE also gives little detailed support for its estimates. In addition to these low confidence factors expressed by ESCOE themselves, ESCOE's cost estimates are outdated relative to Ashland and DOE and simple inflation to 1981 dollars could still underestimate the process costs as they actually occur today. As has been discussed for H-Coal in the previous section, changes in the SRC-II process itself have increased costs at a much higher rate than inflation. For all these reasons, ESCOE's study will be rejected from further consideration in favor of the more recent Ashland and DOE studies evaluation in determining the study with the most accurate process cost estimates. As the ICF cost estimates were also derived from the ESCOE study, their study will also not be analyzed further.

The remaining studies to be analyzed are the Pittsburg and Midway studies, the DOE study and the Parsons study. Of these studies, the Pittsburg and Midway and DOE studies should best represent the process costs of the SRC-II process, based on the following reasons. First, Pittsburg and Midway is under contract with DOE to determine the costs of the 6000 TPD plant to be located near Morgantown, West Virginia and has done all the process development work on SRC-II. Second, both Pittsburg and Midway and DOE have used more recent data to estimate process costs. Parson's was only able to use data available prior to 1978. Third, the Pittsburg and Midway and DOE studies show a more desireable product output. Naptha, which is the most desireable product from coal liquefaction, is about 17 percent of the product output according to the Pittsburg and Midway studies, while in the Parson's study, the naptha production is about 10 percent of total output. Thus, based on the above three reasons, the Pittsburg and Midway studies and the DOE studies will be adjusted separately to all the conditions determined in section II above as these studies most accurately represent and estimate the cost of a future SRC-II commercial plant.

The final adjustments to the DOE and Pittsburg and Midway studies include adjustments for feedstock costs, by-products credits, and annual capital charges. For Pittsburg and Midway, the feedstock rate for a 50,000 BFOE/D plant would be 16,750 tons per day, or for a 365 days per year operation, the feedstock rate

would be 6,113,750 tons per year. At the 1981 estimated coal price of $27.50 per ton, the total feedstock cost would be $168 million. The annual by-product credits of Pittsburg and Midway (already in 1981 dollars) for sulfur and ammonia are $11.0 million per year and $5.9 million per year, respectively. It is assumed that tar acids will not be sold as a marketable by-product.

Pittsburg and Midway estimated the instantaneous capital cost to be $1.23 billion. Using the capital charge rates of 11.5 percent and 30 percent for the low and high cases, respectively, along with the appropriate construction schedules, the annual capital recovery costs are $161 million per year for the low cost case and $414 million per year for the high capital charge rate case.

The total annual cost for Pittsburg and Midway is the sum of the annual capital recovery, operating, and feedstock costs, and less that of the by-product credits. This amounts to $645 million for the high capital charge rate case and $392 million for the low capital charge rate case. The energy value of the products shown in Table 23 is 112,570,380 million BTU per year. The total product cost is then $3.50 per million BTU for the low capital charge rate case and $5.30 per million BTU for the high capital charge rate case.

Next, the DOE study will be further analyzed. DOE's feedstock cost should be the same as that determined for the Pittsburg and Midway study, since as was previously mentioned, both feedstock rates and coal types are identical. This cost is estimated to be $168 million. DOE's annual by-product credits are also the same as determined by Pittsburg and Midway, which amounts to about $17 million.

DOE's instantaaneous capital cost was estimated to be $3.4 billion. Using the adjustment factors mentioned above, the annual capital recovery costs would be $440 million for the low and $1.14 billion for the high capital charge rate case. DOE's total annual cost is the sum of annual capital recovery, operating and maintenance, and less that of by product credits. This amounts to $760 million for the low cost case and $1.46 billion for the high capital charge rate case.

The product energy value in DOE's study is estimated to be 107,673,000 million BTU per year, the same as that estimated by Pittsburg and Midway. The total product cost is then $7.05 per million BTU for the low and $13.56 per million BTU for the high capital charge rate case.

A large discrepancy in product costs exists between the Pittsburg and Midway studies and the DOE study. The DOE product estimates are over twice as large as the Pittsburg and Midway estimates. The primary difference is due to the cost of capital.

After a more thorough investigation, it was found that the 1980 cost estimates of the Pittsburg and Midway study[18] were merely adjusted for inflation from their original 1979 estimates.[12] However, as was discussed in the H-Coal studies earlier, coal liquefaction process costs have tended to rise significantly faster than the rate of inflation due to changes in the processes with time. The Pittsburg and Midway study probably underestimated the latest costs figures as they were merely inflated from previous work. On the other hand, the DOE study may overestimate costs because it was based on a smaller demonstration plant, though the scaling factor (0.75) should help reduce this effect. Thus, although there is some chance of overestimation in the DOE study, it is still likely to be the more realistic. Also, DOE's capital cost is much nearer that for the H-Coal process, while Pittsburg and Midway's capital costs are one-third of that for the H-Coal process and well below that estimated by Parsons' earlier. Thus, the DOE study, with adjustments, appears to be the best product cost estimate for the SRC-II process.

IV. Summary

The publicly available studies addressing the costs of both the H-Coal and SRC-II process were analyzed to determine which contained the most accurate assessment of costs. Two very recent reports by Ashland were found to contain the most up-to-date assessment of the H-Coal process[10,11] and a DOE report was found to contain the most recent cost estimates for the SRC-II process.[20]

The costs contained in each of these studies were placed on a common financial and economic basis, as discussed in section II. The results were that the instantaneous capital cost of a 50,000 BFOE/D H-Coal plant is approximately $3.3 billion (1st quarter 1981). The average product cost would be $5.99 per million Btu with an 11.5 percent annual capital charge rate and $11.47 per million Btu with a 30 percent annual capital charge rate.

The instantaneous capital cost of an SRC-II plant of the same size is $3.4 billion. The average product cost would be $7.05 per million Btu with an 11.5 percent annual capital charge rate and $13.56 per million Btu with a 30 percent annual capital charge rate.

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